

CHAPTER II

THE OUTLOOK FOR ELECTRIC POWER SUPPLY AND DEMAND IN MARYLAND

This chapter presents an overview of the electric utility industry in Maryland and of each individual utility's current plans for meeting anticipated growth in demand over the next 15 years. Beginning with a background description of the industry in Maryland and the present circumstances of the individual utilities, the discussion considers how the utilities operate in the context of the regional power grid. The next section examines the outlook for growth in power demand in Maryland. Both the utilities and PPRP prepare formal demand forecasts, which are presented and compared in this section. With power demands expected to grow over time, Maryland utilities are planning to acquire additional power supply resources and to develop "demand-side" programs. Given these forecasts and resources plans, the next section assesses the future adequacy of service. The final section of this chapter explores in greater detail the alternatives to conventional central station power plants: conservation, load management and non-utility power.

A. Maryland's Electric Utility Industry

Households and businesses in Maryland obtain their electric service from four very large electric utilities and several smaller ones. All of these utilities, publicly- and privately-owned alike, are subject to the regulatory authority of the Maryland Public Service Commission (PSC). Each of these utilities falls into one of three main categories.

- Investor-owned utilities -- Typically, these are large, integrated electric systems engaged in the production, transmission and retail distribution of electricity. Such systems often operate in more than one state and may also sell power on a wholesale basis to distribution utilities. Investor-owned utilities serve approximately 85 percent of Maryland electric customers at retail and produce nearly all of the power consumed in Maryland.

- Rural-electric cooperatives -- The cooperatives are operated by and for their member customers, with financing provided by the federal Rural Electrification Administration (REA). Cooperatives normally serve rural service areas and small towns. None of the Maryland cooperatives operates any significant amount of generating capacity. Virtually all of their power needs are served by bulk purchases from the investor-owned utilities.
- Municipal utilities -- Several medium-sized and small towns in Maryland operate their own electric distribution systems. All of these municipal systems are either in Western Maryland or on the Eastern Shore. Only one municipal, Easton Utilities, generates substantial amounts of electricity.

In addition to power produced by utilities, there has been a resurgence of interest in recent years in power generation from non-utility sources. The owners of such facilities may either sell the power to the utility or use it to serve their own electrical requirements, displacing utility purchases. The Bethlehem Steel facility at Sparrows Point and the Westvaco Corporation in Luke, Maryland generate substantial amounts of power. Further discussion of this subject may be found in Section D of this chapter.

The areas of Maryland served at retail by the various utilities are shown on Figure II-1. The five towns shown on the map are the municipal distribution utilities. Delmarva Power & Light Company (DP&L) and Choptank Electric Cooperative both serve large areas of Maryland's Eastern Shore, and their respective service areas cannot be clearly delineated on a map this size. The map does not show electric utilities lacking retail service areas (generation-only utilities), nor does it show the service areas outside of Maryland served by these utilities.

As the map indicates, the Baltimore metropolitan area, stretching from the northern part of Calvert County to the Pennsylvania border, is served by Baltimore Gas & Electric Company (BG&E). Most of the Maryland suburbs of Washington, D.C. are served by the Potomac Electric Power Company (PEPCO). Taken together, the two areas account for more than 80 percent of the state's population.

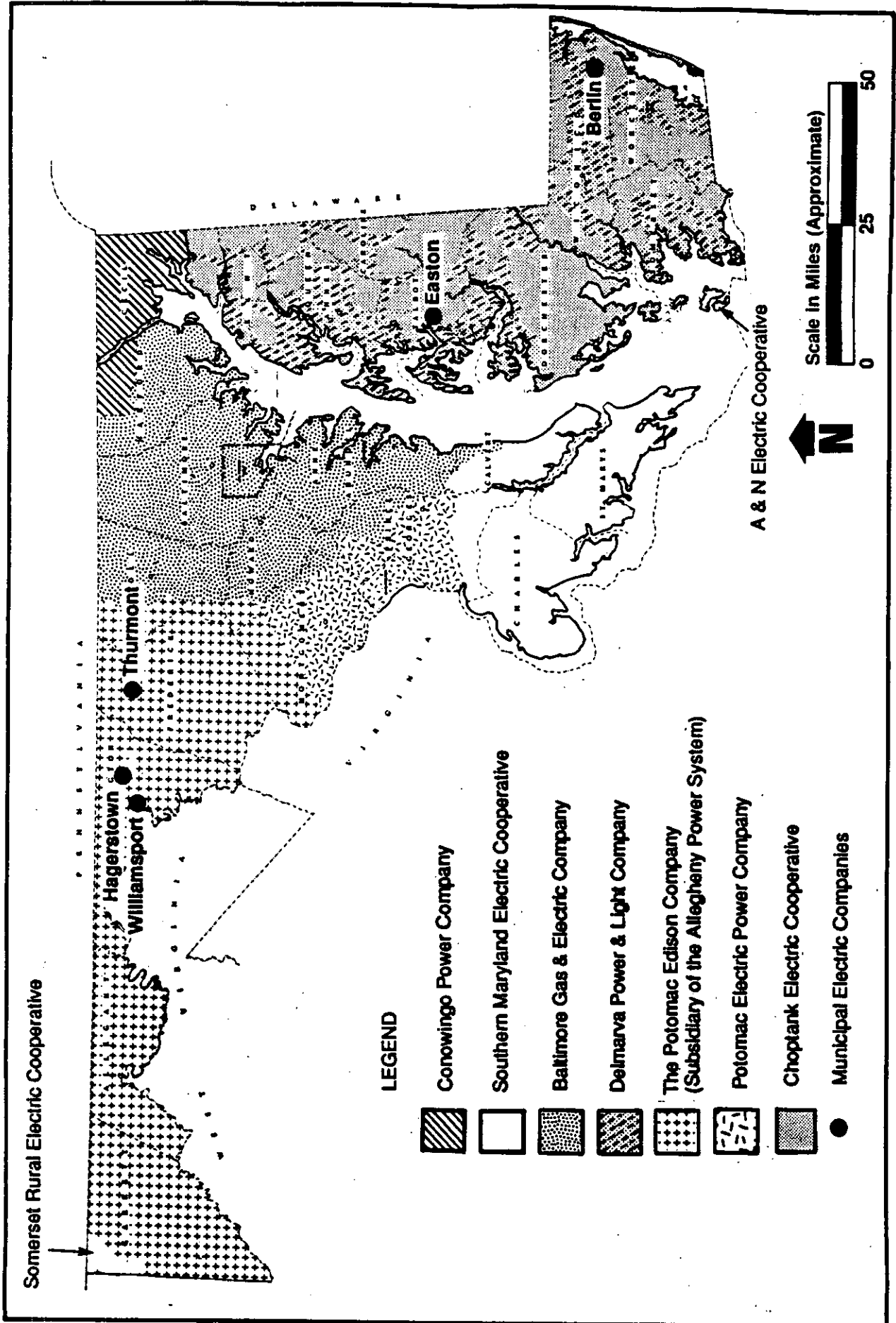


Figure II-1. Service areas of Maryland electric utilities

Table II-1 gives an overview of the operations of Maryland utilities in 1987. The table shows retail sales, generating capacity, annual peak demand, installed generating capacity and the amount of electrical energy generation in Maryland. Three of these utilities, PEPCO, DP&L and Potomac Edison, have substantial retail operations outside of Maryland that are not included on this table. Also excluded are the Somerset Electric and A&N Cooperatives, which serve a very small number of customers in the extreme upper corner of Garrett County and on Smith Island near Virginia, respectively. Two utilities, Susquehanna Electric Company and Pennsylvania Electric Company (Penelec), operate generating units in Maryland but have no retail operations there. Susquehanna and Penelec own the Conowingo (512 MW) and Deep Creek Lake (19 MW) hydroelectric plants. The electric power from these plants largely serves customers outside of Maryland.

As Table II-1 indicates, Maryland's electric utility industry is dominated by investor-owned utilities, particularly PEPCO and BG&E. Such utilities account for virtually all of the electric power generated in the State and the vast majority of the retail sales. The two rural cooperatives have substantial sales (though no generation), and the operations of the municipals are quite small. Only one municipal, Easton Utilities, generates a substantial portion of its load.

The table also indicates that retail sales exceeded generation in 1987, meaning that Maryland is a net importer of electric power (61 million MWh sales versus 36 million MWh generation). This results primarily from the fact that Maryland utilities own power plants sited in neighboring states. DP&L and Potomac Edison account for most of these imports since only a small percentage of the energy they sell is generated in Maryland. Because some of its generating capacity is located in Pennsylvania, BG&E also generates less energy in Maryland than it sells. The one exception is PEPCO. With most of its base load capacity in Maryland, PEPCO produces far more energy in Maryland than it provides to its Maryland retail customers (and SMECO). The excess is exported to the District of Columbia.

The Municipals and Cooperatives

At present, five municipal and four rural cooperatives operate in Maryland. Together they account for approximately 8 percent of Maryland's electric

**Table II-1
Overview of Maryland electric utilities in 1987**

| Utility | Generation (MWh) | Retail Sales (MWh) | | Retail Customers | Peak Demand (MW) | Installed Capacity (MW) |
|-----------------------|---------------------|--------------------|-------------------|---------------------|------------------------|-------------------------------|
| | | Residential | Total | | | |
| Municipals | | | | | | |
| Berlin | 0 | 825 | 2,522 | 1,376 | 6 | 4 |
| Easton | 64,645 | 51,924 | 154,811 | 6,580 | 36 | 45 |
| Hagerstown | 0 | 99,944 | 262,795 | 17,123 | 59 | 0 |
| Thurmont | 0 | 17,064 | 43,054 | 1,665 | 9 | 0 |
| Williamsport | 0 | 8,486 | 13,989 | 850 | 4 | 0 |
| Subtotal | 64,645 | 178,243 | 477,171 | 27,594 | 114 | 49 |
| Cooperatives | | | | | | |
| Choptank | 0 | 304,344 | 405,613 | 29,088 | 94 | 0 |
| SMECO | 0 | 958,512 | 1,566,205 | 81,314 | 387 | 0 |
| Subtotal | 0 | 1,262,856 | 1,971,818 | 110,402 | 481 | 0 |
| Investor-Owned | | | | | | |
| BG&E | 18,255,152 | 8,521,381 | 22,574,965 | 956,369 | 5,190 | 5,287 |
| DP&L | 378,530 | 939,890 | 1,994,198 | 110,643 | 2,030 | 180 |
| Potomac Edison | 538,743 | 1,731,839 | 6,309,565 | 295,274 | 1,682 | 110 |
| PEPCO | 16,403,756 | 4,276,714 | 10,994,403 | 391,097 | 5,153 | 4,432 |
| Conowingo | 0 | 295,167 | 554,929 | 29,757 | 119 | 0 |
| Subtotal | 35,576,181 | 15,764,991 | 42,428,060 | 1,783,140 | 14,174 | 10,009 |
| Grand Total | 35,640,826 | 17,206,090 | 44,877,049 | 1,921,136 | 14,769 | 10,058 |

Source: Utility 1987 annual reports filed with the Maryland Public Service Commission (Williamsport: 1986 Annual Report).
N.B.: All figures are Maryland jurisdiction except for peak demand, which is systemwide.

customers but less than one percent of total generating capacity in the state. They are therefore heavily reliant upon power purchases from the investor-owned utilities.

Two of the five municipals, Berlin and Easton, are located on the Eastern Shore. Berlin obtains nearly all of its power from DP&L, although it maintains a small amount of capacity for peak shaving purposes. Easton is self-sufficient in that it has sufficient capacity to serve its peak load; however, it purchases substantial amounts of power from DP&L to save fuel expense. The three Western Maryland municipals of Hagerstown, Thurmont and Williamsport obtain all of their power from Potomac Edison. Hagerstown owned some generating capacity, but the plant has been officially retired.

The two major cooperatives are Choptank Electric Cooperative and Southern Maryland Electric Cooperative (SMECO). Neither system has any generating capacity at present, but both have plans for doing so in the future. Choptank (along with other cooperatives on the Eastern Shore) intends to obtain a portion of the Nanticoke coal-fired plant proposed by DP&L. Choptank's participation would take place indirectly through the Old Dominion Electric Cooperative. SMECO, which is currently a full requirements customer of PEPCO, plans to construct some combustion turbine peaking capacity. It presently has in place a residential load management program designed to reduce demands for short periods during those hours when power demands are greatest.

The Investor-Owned Utilities

Seven investor-owned electric utilities operate in Maryland, of which five provide retail service. Penelec, which operates the Deep Creek Lake hydroelectric plant, is a subsidiary of General Public Utilities, a public utility holding company. Aside from that plant, it has no operations in Maryland.

Susquehanna Electric Company, which operates the Conowingo hydroelectric plant, exports virtually all of the power from that plant to its parent, Philadelphia Electric Company. Conowingo Power Company, a wholly-owned subsidiary of Philadelphia Electric, provides retail service to nearly 30,000 customers in Cecil

County, Maryland. Conowingo has no generating capacity of its own, obtaining all of its required power from its parent through wholesale purchase. It is the smallest of the investor-owned utilities.

Baltimore Gas & Electric Company has the largest Maryland operations of all the investor-owned utilities. BG&E serves Baltimore City and most or all of the surrounding suburban counties. Its service area is thus a mixture of urban and suburban. BG&E also has a substantial industrial (i.e., manufacturing) load, although the industrial portion of the local economy has been gradually declining over the past decade. In 1987, BG&E experienced a peak demand of 5,190 MW, compared to its installed capacity of 5,287 MW (summer ratings). This installed capacity is a mixture of nuclear, coal, hydroelectric, oil and gas. The Calvert Cliffs nuclear plant accounts for about 30 percent of the Company's generating capacity but more than 50 percent of the generation.

PEPCO is approximately the same size as BG&E on a system-wide basis, but Maryland accounts for only about 60 percent of PEPCO's operations, the District of Columbia accounting for the remaining 40 percent.¹ Like BG&E, PEPCO's service area is a mixture of urban and suburban customers, with the suburban portion exhibiting the more rapid growth. One important difference, however, is that PEPCO serves virtually no heavy manufacturing firms. In 1987, PEPCO's peak demand (system wide) was 5,153 MW. During the past several years, approximately 90 percent of PEPCO's generation came from its coal-fired units, with the remainder being oil and gas-fired generation. PEPCO has also made extensive use of purchased power and will continue to do so in the future. In 1987, PEPCO entered into a 19-year purchased power contract with the Ohio Edison Company, allowing PEPCO to purchase up to 450 MW.

Potomac Edison Company (PE) serves the Western Maryland region along with contiguous areas of Virginia and West Virginia. The Company is a subsidiary of the Allegheny Power System (APS) holding company, which also owns Monongahela Power Company (MP) and West Penn Power Company (WPP). Because all three companies are jointly operated and planned as a single utility

¹ Until recently, PEPCO also served a small portion of the Northern Virginia suburbs, but that territory has been transferred to Virginia Power Company. However, PEPCO has retained possession of the coal-fired Potomac River power plant located in Virginia.

system, most of the discussion in this chapter will refer to APS rather than PE. MP serves the northern portion of West Virginia and a small area in Ohio, while WPP serves the southwestern portion of Pennsylvania. Maryland comprises about two-thirds of PE's sales and 20 percent of the entire APS. APS serves no large metropolitan areas. Its service territory is largely rural and suburban and contains a substantial amount of heavy industry. Both PE and APS are winter peaking; Maryland's other major electric utilities experience their greatest annual demands in the summer.

In 1986, the APS peak was 5,674 MW and PE's was 1,691 MW -- compared to their installed ("active") capacities of 7,961 MW and 2,065 MW, respectively. Virtually all of the electric power generated by APS is from coal-fired plants. APS owns 840 MW of the 2,100 MW Bath County Project operated by Virginia Power Company. This is a pumped storage hydroelectric plant that is used mostly to serve APS' peaking needs.

Delmarva Power & Light Company (DP&L) serves directly or indirectly virtually all of the power requirements on the Delmarva Peninsula. The only entities on the peninsula that provide significant amounts of their own electric power are Dover, Delaware and Easton, Maryland. This region includes the entire state of Delaware, the Eastern Shore counties of Maryland and the two Virginia counties of Accomack and Northampton. DP&L's service area is very heterogenous. In the northern part of Delaware, DP&L serves the Wilmington metropolitan area, a large urban/suburban complex. Northern Delaware also has substantial heavy industry. Most of the rest of the peninsula is rural and small town, with some light manufacturing and major ocean resorts. Maryland accounts for approximately 25 percent of the DP&L system. DP&L has a very large wholesale sector, approximately 17 percent of its total sales in 1986. DP&L's peak demand in 1986 was 1,788 MW compared to installed capacity of 2,277 MW. DP&L's capacity is a mix of nuclear, coal and gas/oil. Its nuclear capacity consists of small percentages of four generating units at the Peach Bottom and Salem generating stations, which are operated by other utilities.

Interactions Among Utilities

Understanding the interactions among the utilities is important to understanding Maryland's electric utility industry. All wholesale power transactions are governed by the Federal Energy Regulatory Commission (FERC). Power transactions among utilities fall into two general categories: "economy" and "firm." Economy transactions are made when the utility operators decide that it is less expensive to import power increments from another utility than to generate from the utility's own units. They are the most common type of transaction and are typically short-run in nature; but they can involve contract commitments as reserved economy for longer periods. Firm transactions involve a contract commitment on the part of the seller over a specific time period to supply (or stand ready to supply) a predetermined amount of power. Firm purchased power arrangements are designed to make more effective use of generating reserves, and they enable the buyer to postpone power plant construction.

In order to realize fully the efficiency and reliability benefits of power transactions, the Maryland utilities participate in multi-utility power pools. PE and its two utility affiliates form the APS power pool. All the units owned by the three members are centrally dispatched economically in order to minimize fuel costs. APS also performs all generation planning in a centralized fashion, taking into account the needs of the entire system. The pricing of the power transactions and the assignment of cost responsibility for reserves among the members is governed by the APS Power Supply Agreement.

PEPCO, BG&E and DP&L are members of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) power pool, which also includes most of the electric utilities in Pennsylvania, New Jersey, Delaware, and the District of Columbia. PJM's installed capacity is nearly 48,000 MW (NERC 1987). By coordinating the operations of the pool members, PJM facilitates the most efficient possible usage of the generating units and provides greater reliability of supply for all pool members.

The PJM pool attempts to achieve minimum cost operation for its members through a practice known as "economic dispatch." In general, a utility system

tries to serve its load at minimum expense by making maximum use of its lowest operating-cost generating units (i.e., baseload coal or nuclear) and only dispatching the higher-operating-cost units (i.e., oil or gas) when the baseload units are running at their maximum levels. PJM facilitates this process. The PJM central office collects plant operating data on all PJM plants and continuously determines the pool-wide incremental cost of generating each additional kWh. All of the members' units are operated as a single system in which generation is added from the most economical source available - regardless of ownership - to meet the next increment of load. Interchange accountants later determine how much each company was buying from or selling to other members of the pool. Through this system of economic dispatch and after-the-fact accounting, economies of operation are realized.

Unlike APS, the individual PJM companies perform their own planning for new generation and transmission facilities. PJM establishes criteria or standards for reserves and also performs an enforcement role. For example, PJM may assess a member utility a penalty for failure to maintain sufficient generating reserves. Power pooling thus helps to bring about more economical use of existing generating plant, coordination among members of future capacity additions and improved power supply reliability.

In addition to participating in power pools, the Maryland utilities are members of regional reliability councils. In 1966, the North American Electric Reliability Council (NERC) was formed in order to promote the reliability of bulk power supply in North America. It presently includes nine regional councils and one affiliate, which encompass virtually the entire U.S. and Canada. Their chief function is to monitor loads and power resources and to conduct studies of reliability. The councils also establish certain reliability standards such as spinning reserve requirements (requirements that certain generators be kept running but not generating electricity, so that they can quickly be placed in service in an emergency). PEPCO, BG&E and DP&L are members of the Mid-Atlantic Area Council (MAAC), and Potomac Edison is a member of East Central Area Reliability Coordination Agreement (ECAR).

Table II-2 illustrates the importance of "off-system" transactions for Maryland utilities in 1986. It lists the amount of power purchased from and sold to other utility systems that year. The bottom row, net imports, is simply the difference between sales off-system and purchases. To provide a basis for comparison, the top row of the table lists the utility's sales that year to its regular retail and wholesale customers. As the data indicate, transactions with other utilities are large for all four companies; but their net export positions differ. Potomac Edison imports approximately the same amount of power as it exports, though most of the imports are from WPP and MP, its affiliates. APS as a whole is a major net exporter of power. PEPCO and (to a lesser extent) DP&L are large importers of power. PEPCO's net imports that year equaled more than 20 percent of its system sales. With its new Ohio Edison purchased power contract, these net increases are expected to continue. BG&E was a substantial net exporter of power in 1986, reflecting its ample generating reserves that year.

B. The Power Supply Resource Plans Of Maryland's Utilities

This section reviews the anticipated growth in power demand over the next 15 years for Maryland's major electric utilities and their resource plans for meeting those needs. Resource plans are broad in scope, including conventional power plants as well as demand-side programs, purchased power and the development of non-utility power. The use of a comprehensive analytical framework to evaluate all types of resource options, as currently employed by Maryland utilities, is commonly referred to as "integrated resource planning."

The planning environment in Maryland has changed substantially in the last three years, inducing the utilities to alter their plans in important ways. With the exception of APS, power demands have grown far more rapidly than the utilities have anticipated. The emergence of this need-for-power problem has also stimulated utility interest in load management programs. A second change is a moderation or decline in prices for fuel, particularly oil. The increased growth rate has led the utilities to accelerate their schedules for new capacity resources. The lower oil prices that currently prevail, combined with the relatively low cost of combustion turbine units and the utilities' desire for smaller increments of

Table II-2
1986 off-system transactions of Maryland utilities
(thousands MWh)

| | DP&L | BG&E | PEPCO | Potomac Edison |
|--|------------|--------------|------------|-------------------|
| System sales ^(a) | 9,206 | 21,236 | 20,762 | 8,905 |
| Purchases from other utilities ^(b) | 1,824 | 1,949 | 4,870 | 3,114 |
| Sales to other utilities ^(c) | <u>786</u> | <u>4,010</u> | <u>972</u> | <u>3,234</u> |
| Net imports (exports) ^(d) | 1,038 | (2,061) | 3,898 | (120) |

Source: 1986 Annual Report to the Maryland Public Service Commission for each company.

- ^(a) Retail sales plus firm sales to those wholesale customers that are considered part of the system.
- ^(b) For BG&E, purchases exclude power from Safe Harbor (a BG&E affiliate). Figures include purchases from non-utility generation.
- ^(c) For BG&E, figures exclude sales to Bethlehem Steel.
- ^(d) Imports equal purchases minus sales to other utilities.

generation, all tend to make combustion turbine peaking plants (as opposed to baseload coal plants) more attractive than in previous years.

From the late 1970's through 1984, load growth was relatively slow, increasing at a compound rate of approximately two percent per year for DP&L, PEPCO and BG&E. Load growth has accelerated sharply since then, increasing by five to eight percent per year for these three companies. This rapid growth is partly attributable to unusually hot peak day weather in 1987. On a more fundamental level, the acceleration in load growth occurred because of very strong service area economies,² and secondly because electric rates have either fallen or increased less rapidly than inflation.

As a result of this recent experience, PEPCO and DP&L have revised their load forecasts upwards. In 1985, PEPCO projected year 2000 peak demand of 5,430 MW, and DP&L projected peak demand of 1,952 MW. Their current projections for year 2000 are 6,081 MW and 2,455 MW, respectively. BG&E has increased its year 2000 forecast peak from 5,860 MW to 6,070 MW, even though it assumes larger load management savings in its current forecast.

Another resource that has increased in importance in recent years is the emergence of non-utility generation. APS anticipates nearly 1,000 MW of non-utility generation on its system by the mid-1990's. Based upon projects now in the conceptual development stage, 500 MW or more of this resource may become available to PEPCO within the next several years. DP&L is also including in its capacity plan a significant amount of non-utility power.

The outlook for growth in power demand, and the resource plans designed to meet that growth, are described below for APS, BG&E, DP&L and PEPCO. The discussion utilizes the forecasts and resource plans that the utilities filed with the Maryland PSC in December 1987 (January 1988 for BG&E) as part of the Ten-Year Plan filing requirements. The Ten-Year Plan, prepared annually for the Department of Natural Resources, reviews forecasts of peak loads and energy sales, utility expansion plans and demand-side management programs. Later in

² See Appendix A for a discussion of the Maryland economy and its outlook.

this section, load projections prepared by the Power Plant Research Program are presented for comparative purposes.

The Allegheny Power System

The peak demand forecast and capacity additions over the next 15 years for APS are shown on Table II-3. Demand growth has been slow during the last several years, reflecting the underlying economic weakness in the APS service area. Modest growth (1.7 percent per year) during the next 15 years is anticipated.

As a result of weak demand conditions in its service territory and the addition of 840 MW from the Bath plant in 1985, APS has more generating resources than required to serve its native load. It has entered into a purchased power agreement to sell up to 300 MW to the Old Dominion Electric Cooperative from the winter of 1987-88 through 1994.

For the past several years, APS expected to serve its future load growth by constructing a series of 300 MW coal-fired plants. The 1986 CEIR reported that APS would construct four such plants between 1995 and 2000, based on the plan that PE filed at the Maryland PSC in 1985.

The current plan is quite different. All increases in capacity through 1995 will come from non-utility power plants that sell their power output to APS companies. APS' current plan lists the potential for 17 such projects, totaling 997 MW, during the 1988 to 1995 time period.³ In addition to the projected increases, the APS presently receives 125 MW from the Beaver Valley AES project, which entered service in 1987, and some miscellaneous small projects. APS has not identified the specific non-utility projects listed in its current capacity plan, in order to meet the confidentiality requirements of the developers.

No non-utility projects are identified for the period beyond 1995. In 1997 and 1998, APS will obtain 361 MW by reactivating the Springdale and Mitchell plants, oil-fired steam units that are currently in cold storage reserve. APS projects the need

³ Because of the potential uncertainties with these projects, APS reduces the capacity by a 167-MW "contingency." This reduces the amount of projected new non-utility capacity to 695 MW. (See 1987 Fifteen Year Plan of the Potomac Edison Company.)

Table II-3
Allegheny Power System
Projected peak demand, capacity and reserves
(megawatts)

| Year ^(a) | Annual Peak Demand | Net Capacity Additions | Capacity Sale ^(b) | Total Capacity | Reserve Margin |
|---------------------|--------------------|------------------------|------------------------------|----------------|----------------|
| 1988 | 5,999 | 125 | (260) | 7,846 | 30.8% |
| 1989 | 6,098 | 39 | (300) | 7,845 | 28.7 |
| 1990 | 6,215 | 7 | (300) | 7,852 | 26.3 |
| 1991 | 6,245 | 127 | (300) | 7,979 | 27.8 |
| 1992 | 6,346 | 306 | (300) | 8,285 | 30.6 |
| 1993 | 6,454 | 41 | (300) | 8,326 | 29.0 |
| 1994 | 6,565 | 0 | (300) | 8,326 | 26.8 |
| 1995 | 6,706 | 0 | 0 | 8,626 | 24.2 |
| 1996 | 6,832 | 185 | 0 | 8,811 | 29.0 |
| 1997 | 6,941 | 0 | 0 | 8,811 | 26.9 |
| 1998 | 7,050 | 154 | 0 | 8,965 | 27.2 |
| 1999 | 7,194 | 207 | 0 | 9,172 | 27.5 |
| 2000 | 7,345 | 10 | 0 | 9,182 | 25.0 |
| 2001 | 7,474 | 160 | 0 | 9,342 | 25.0 |
| 2002 | 7,565 | 119 | 0 | 9,461 | 25.1 |

Source: Ten-Year Plan filing with the Maryland Public Service Commission.

^(a) "Year" refers to winter ending in the designated year. For example, 1988 is the winter of 1987/1988.

^(b) "Capacity sale" refers to 300 MW sale of Old Dominion Electric Cooperative. This has been subtracted from "Total Capacity".

for 540 MW of new capacity during 1999 to 2002, but has not indicated the type of capacity or resource that will fill this need.

Two other major changes since the last CEIR include further load reductions from the extension of demand management programs beyond 1995 and delayed plant retirements. The present APS plan assumes 900 MW of savings from demand-side programs over the 15-year period (which is reflected in the load projections on Table II-3). The only plant retirement identified by APS is 141 MW from the Rivesville units 5 and 6 in 2001.

The far right column of Table II-3 shows the projected APS reserve margin, calculated as available installed capacity minus annual peak demand divided by peak demand. Generating reserves are needed because of generating unit down time and uncertainties in projecting power demands. For example, extreme weather may cause large unanticipated fluctuations in demand. APS utilizes a minimum planning reserve margin of 25 percent. During the period of 1988 to 2002, projected reserves remain in the 25 to 30 percent range, according to this plan.

In summary, due to anticipated slow load growth, demand management and the abundance of non-utility generation projects in the region, APS has no plans to construct any new capacity. It projects that new generating resources will be needed by approximately year 2000, but even this will not necessarily be met through APS construction.

Baltimore Gas & Electric Company

The BG&E system has experienced unusually rapid growth in power demand during the last few years. This is partly due to unusually hot peak day weather, but it is also attributable to a very strong local economy. This has resulted in upward revisions to its load forecast, despite the fact that BG&E has recently introduced new load management programs. Table II-4 presents BG&E's latest load forecast and capacity plan ("base case"), with the estimated load management reductions incorporated into the annual peak demand figures. It should be noted that the projections assume that BG&E will become winter-peaking in 1997.

Table II-4
Baltimore Gas & Electric Company
Projected peak demand, capacity and reserves
(megawatts)

| Year | Annual Peak Demand | Net Capacity Additions | Total Capacity ^(a) | Reserve Margin |
|---------------------|--------------------|------------------------|-------------------------------|----------------|
| 1988 | 5,110 | 7 | 5,904 | 15.5% |
| 1989 | 5,180 | 65 | 5,969 | 15.2 |
| 1990 | 5,250 | 226 | 6,195 | 18.0 |
| 1991 | 5,320 | 71 | 6,266 | 18.0 |
| 1992 | 5,370 | 385 | 6,651 | 23.9 |
| 1993 | 5,440 | 0 | 6,651 | 22.3 |
| 1994 | 5,500 | 0 | 6,651 | 20.9 |
| 1995 | 5,560 | 0 | 6,651 | 19.6 |
| 1996 | 5,620 | 0 | 6,651 | 18.4 |
| 1997 ^(b) | 5,740 | 285 | 6,936 | 20.8 |
| 1998 | 5,860 | 71 | 7,007 | 19.6 |
| 1999 | 5,970 | 83 | 7,090 | 18.8 |
| 2000 | 6,070 | 58 | 7,148 | 17.8 |
| 2001 | 6,170 | 210 | 7,358 | 19.3 |
| 2002 | 6,280 | 160 | 7,518 | 19.7 |

Source: Ten-Year Plan filing with the Maryland Public Service Commission.
(Base case forecast and plan.)

^(a) Total capacity includes 169 MW from Bethlehem Steel.

^(b) Switch to a winter peak is anticipated in 1997. Beginning in that year, winter capacity ratings are included under total capacity. The gain in 1997 from using winter ratings is 294 MW.

BG&E's major new resource is the Brandon Shores Unit 2, a 640-MW coal-fired plant scheduled for service in 1992. This will significantly increase the percentage of coal-fired capacity on the system.

Other than Brandon Shores Unit 2, which is a committed resource, BG&E's current capacity plan heavily emphasizes flexibility. Specifically, the plan is designed to allow adjustments with relatively short lead times to changes in forecasted loads. The two major elements of the plan include a 12-year purchased power agreement with Pennsylvania Power & Light Company (PP&L), which extends over the period 1990 to 2001, and the construction of combustion turbine and combined cycle capacity. Compared to the construction of new base load capacity, these two sources involve much smaller capital commitments.

The purchased power agreement recently reached with PP&L contains two components. The first is a 125 MW share of the Susquehanna nuclear plant, with BG&E paying for its allocated share of the plant and the associated transmission path to the BG&E grid. The second part provides options for taking peaking capacity -- initially up to 600 MW, but dropping to a maximum of 275 MW after October 1991. BG&E's ability to vary its take of this peaking capacity is the source of the flexibility.

The addition of the combustion turbine and combined cycle capacity is scheduled for 2001, with another 160 MW combustion turbine plant to be added in 2002. The base case plan indicates 480 MW of combustion turbine capacity plus an additional 130 megawatts associated with the heat recovery portion of the combined cycle plant, for a total of 610 MW (winter ratings). However, BG&E will also be losing 400 MW from the termination that year of the PP&L contract. The net addition of resources that year is thus 210 MW.

The above discussion identifies the major elements of BG&E's resource plan - 640 MW from Brandon Shores 2, 400 MW of purchased power, 770 MW of combustion turbines/combined cycle and about 200 MW of load management. The plan also includes 55 MW of non-utility power in 1989 from Baltimore Refuse Energy Systems Company (BRESKO), the mothballing of Westport Units 3 and 4 in 1992

(126 MW) and 53 MW of unit upratings. BG&E's present capacity plan thus emphasizes a diversity of power sources.

Delmarva Power & Light Company

For the past several years, DP&L has filed resource plans with the PSC delaying or reducing the size of the company's next major generating unit, the Nanticoke coal-fired plant. In 1981, the Commission granted DP&L a license to construct that plant as a 500 MW unit at the company's Vienna, Maryland site. A pronounced slowing in the growth of power demands during the next several years motivated the deferrals and downsizing.

Very rapid load growth, unanticipated by DP&L, has occurred during the last two years. In response to this change, the company filed a planning framework with the Maryland PSC (April 1987) referred to as "Challenge 2000." This plan identifies the various resource options that the company intends to pursue. It contemplates load management programs, non-utility generation, installation of combustion turbines and, later in the 1990's, a small coal-fired plant possibly using fluidized bed technology (Jones 1987).

In October 1987, DP&L filed an announcement with the Maryland PSC indicating its intent to construct two 100 MW combustion turbine peaking units in New Castle County in Northern Delaware (Wittine 1987). The anticipated on-line dates for those units are 1989 and 1990. The announcement also indicated that DP&L is considering siting the units at its Vienna, Maryland site if it encounters difficulty with the licensing process in Delaware. According to the company, the proposed combustion turbine plant is the only feasible and economically attractive means available to enable it to maintain reliability of service over the next several years. DP&L's current load forecast and capacity plan, as filed with the Maryland PSC, shows load savings from demand-side programs, which DP&L expects to achieve by the mid-1990's. On the capacity side, Table II-5 indicates the installation of the 100 MW combustion turbine units in 1989 and again in 1990. The additional capacity of approximately 35 MW between 1988 and 1991 comes from upgrades to DP&L's existing power plants.

Table II-5
Delmarva Power & Light Company
Projected peak demand, capacity and reserves
(megawatts)

| Year | Annual Peak Demand | Net Capacity Additions | Total Capacity | Reserve Margin |
|------|--------------------------|------------------------------|-------------------|-------------------|
| 1988 | 2,058 | 7 | 2,284 | 11.0% |
| 1989 | 2,117 | 109 | 2,393 | 13.0 |
| 1990 | 2,149 | 114 | 2,507 | 16.7 |
| 1991 | 2,176 | 5 | 2,512 | 15.4 |
| 1992 | 2,197 | 0 | 2,512 | 14.3 |
| 1993 | 2,214 | 0 | 2,512 | 13.5 |
| 1994 | 2,188 | 100 | 2,612 | 19.4 |
| 1995 | 2,205 | 0 | 2,612 | 18.5 |
| 1996 | 2,234 | 0 | 2,612 | 16.9 |
| 1997 | 2,278 | 0 | 2,612 | 14.7 |
| 1998 | 2,323 | - | - | - |
| 1999 | 2,368 | - | - | - |
| 2000 | 2,412 | - | - | - |
| 2001 | 2,456 | - | - | - |
| 2002 | 2,500 | - | - | - |

Source: 1987 Ten-Year Plan filing with the Maryland Public Service Commission.
 N.B.: DP&L's current capacity plan extends only through 1991. Capacity figures beyond 1991 are options being evaluated.

DP&L has no firm plans beyond 1991 and identifies no capacity figures after 1997. This table assumes the 150 MW Nanticoke 1 coal-fired unit will enter service in 1994. DP&L will own 100 MW of its capacity, and the Old Dominion Electric Cooperative will own the other 50 MW.⁴ DP&L uses a 15 percent minimum reserve margin for planning purposes. According to Table II-5, this level of reliability is approximated for most years through 1997.

Potomac Electric Power Company

Over the past several years, PEPCO has taken a number of steps to add resources to its system. This has taken the form of a large scale load management program, long-term purchased power and new power plant construction.

Table II-6 presents PEPCO's latest load forecast and its recommended capacity plan. The load projections reflect expected savings from the company's Energy Use Management Program. However, new load management programs being considered for the future are included under the "new capacity additions" column. In 1987, PEPCO entered into a 450 MW purchased power contract with the Ohio Edison Company extending through the year 2005. PEPCO obtained 200 MW beginning in July 1987, with the remaining 250 MW to be acquired by the end of 1989. This power will help PEPCO to meet its near-term capacity requirements and, over the life of the contract, will displace generation from PEPCO's high operating cost units. The power is transmitted from Ohio to PEPCO's service territory through the Allegheny Power System's transmission grid.

In June 1987, PEPCO applied to the Maryland PSC for a certificate of public convenience and necessity for "Station H" (PEPCO 1987b). The Application is for the construction of two coal gasification combined cycle (GCC) generating units, each having a rated capacity of 375 MW. The two units are to be sited at PEPCO's Dickerson power station in upper Montgomery County, which currently operates three coal-fired units.

⁴ With Old Dominion obtaining a 50 MW share of the plant's output, DP&L's peak load declines by the same amount. Hence DP&L's total peak load decreases from 1994 to 1993.

**Table II-6
Potomac Electric Power Company
Projected peak demand, capacity and reserves
(megawatts)**

| Year | Annual Peak Demand | Net Capacity Additions ^(a) | Total Capacity | Reserve Margin |
|------|--------------------|---------------------------------------|----------------|----------------|
| 1988 | 5,036 | 100 | 5,675 | 12.7% |
| 1989 | 5,116 | 150 | 5,825 | 13.9 |
| 1990 | 5,175 | 70 | 5,895 | 13.9 |
| 1991 | 5,220 | 145 | 6,040 | 15.7 |
| 1992 | 5,278 | 93 | 6,133 | 16.2 |
| 1993 | 5,365 | 62 | 6,195 | 15.5 |
| 1994 | 5,455 | 147 | 6,342 | 16.3 |
| 1995 | 5,543 | 141 | 6,483 | 17.0 |
| 1996 | 5,651 | 140 | 6,623 | 17.2 |
| 1997 | 5,754 | 17 | 6,640 | 15.4 |
| 1998 | 5,863 | 141 | 6,781 | 15.7 |
| 1999 | 5,973 | 138 | 6,919 | 15.8 |
| 2000 | 6,081 | 137 | 7,056 | 16.0 |
| 2001 | 6,189 | 139 | 7,195 | 16.3 |
| 2002 | 6,305 | 139 | 7,334 | 16.3 |

Source: 1987 Ten-Year Plan filing with the Maryland Public Service Commission.

^(a) Net capacity additions and total capacity include the Ohio Edison purchased power contract and new Energy Use Management (EUM) program savings.

The Commission's consideration of the Application is divided into phases. Hearings for the first phase, site selection, began in late September 1987 and were concluded in early January 1988. Candidate sites in Maryland were reviewed on the basis of environmental impacts, engineering considerations, economics, and socioeconomic impacts. PEPCO has argued that Dickerson is the preferred site among the candidates on the basis of cost (mostly coal transportation) and system reliability (Benziger 1987). PPRP's preliminary site assessment has found Dickerson to be an acceptable site for Station H, as well as being the least-cost site among the candidates (MD-DNR 1988). A Commission decision on site selection is expected in 1988. [To Be Updated In Final Version]

The second phase of the Application review process, expected to commence in 1988, will investigate PEPCO's need for new power generating facilities and the appropriateness of PEPCO's capacity expansion or resource plan. Subsequent phases will deal with issues of detailed technical design of the proposed plant (and its components) and the results of site-specific environmental analysis for each stage of the Station H plant.

The GCC plant consists of four phases or "modules" that are ultimately integrated into a single facility. The first two phases are oil or gas-fired combustion turbines of 125 MW each in PEPCO's design. Stage 3 (also rated at 125 MW) is a steam turbine plant, which also burns oil or gas and recovers the waste heat from the first two phases. The three phases function together as a conventional "combined cycle" plant. The fourth and last stage is the gasifier, which converts coal into synthetic gas to be consumed by Phases 1-3. The gasifier is the most expensive part of the plant and can be deferred (or cancelled) if its cost is not justified, leaving the other three phases intact and functioning. This gives the GCC a flexibility that other baseload generating technologies do not have.

According to PEPCO's license application, the initial increment of capacity is scheduled to enter service in 1994, with additional phases entering service each year through 2001. However, PEPCO's "recommended" plan contained in the 1987 Energy Plan includes only the combustion turbine phases. The steam cycle and gasifier are only economically attractive if oil and gas market prices become sufficiently high compared to that of coal.

Table II-6 indicates other capacity additions prior to 1994, which are expected to come from several sources. PEPCO plans to add approximately 140 MW of combustion turbine capacity in 1990 or 1991 at its Benning Road station in the District of Columbia. SMECO has filed an application with the Maryland PSC to construct two 30 MW turbine units (SMECO 1988). The units will be sited at PEPCO's Chalk Point station in Southern Maryland, and the power will be made available to PEPCO. Montgomery County also has plans to construct a waste-to-energy facility at Dickerson, which will provide PEPCO with approximately 40 MW. That project is included in PEPCO's current capacity plan with an in-service date of 1993 (PEPCO 1987d).

One of the major uncertainties facing PEPCO at the present time is non-utility power development. PEPCO's 1987 Energy Plan has identified more than 500 MW of potential capacity additions. These projects are largely in the discussion and conceptual development stage and, with the exception of a Montgomery County facility that will use solid waste for fuel, have not been included in PEPCO's capacity plan. If a substantial percentage of this capacity emerges in the next few years, PEPCO's current resource plan will change substantially, and the proposed GCC units would probably be deferred.

Table II-6 demonstrates PEPCO's immediate need for new capacity. Even with nearly 500 MW of new capacity between now and 1991, PEPCO's projected reserve margin averages less than 15 percent. Between 1991 and 2002, PEPCO projects a reserve margin between 15 and 17 percent. This result is attained through annual capacity additions that follow the projected load growth.

Comparison with PPRP Forecasts

The capacity plans of the utilities are specifically tailored to each utility's forecast of its customers' power demands. Because of the importance of the load forecast for the planning process, PPRP has been conducting its own program of load forecast studies on a regular basis in order to provide an independent assessment of the need for new capacity by the Maryland utilities. The studies are used to monitor the adequacy of service in Maryland and have been introduced in planning or

certifications before the Maryland PSC. Load forecasts have been performed for each of the four major systems along with periodic updates.

The studies were conducted by developing and applying sets of econometric models, consisting of equations that relate electric power usage to the various factors that explain that usage. Once the models are developed, it is necessary to formulate assumptions concerning population, growth in the local economy, electricity prices and other variables in the equations. To the extent possible, the studies rely upon published data and projections available from official sources such as the Department of State Planning. (See Appendix A.)

The forecasts prepared by PPRP for annual peak demand for the period 1988-2002 are presented on Table II-7. There are some difficulties in comparing these forecasts directly with those prepared by the utilities. The PPRP forecast for Delmarva is that of the "DP&L Group" (including the Dover and Easton loads), whereas the forecasts supplied by the company exclude those loads (about 125 MW). The PPRP forecasts include load management savings based upon program estimates available at the time those studies were prepared. DP&L and APS have increased these savings quite substantially in their more recent forecasts.

Table II-8 indicates that the PPRP forecasts are somewhat higher than those of the utilities. For APS, DP&L and PEPCO, these differences are not large in percentage terms. The difference with APS is largely attributable to the fact that the utility has provided its load management savings estimates for the entire 15-year period in its current forecast. The PPRP forecast for APS includes some load management-induced reductions, but a far smaller amount. The only large and unexplained difference is between PPRP and BG&E, with PPRP projecting significantly more rapid growth. The PPRP forecast is about 6 percent higher in 1995, with the difference increasing to 12 percent by 2002.

C. Assessing Future Adequacy of Service

Utilities attempt to plan their systems in order to serve their customers' power demands with a high degree of reliability and the lowest feasible costs. (Other criteria include financial feasibility, environmental impacts, impacts on electric

**Table II-7
PPRP systemwide peak demand forecasts
(megawatts)**

| Year | DP&L ^(a) | BG&E ^(b) | PEPCO ^(b) | APS ^(c) | Potomac Edison ^(c) |
|--|---------------------|---------------------|----------------------|--------------------|-------------------------------|
| 1988 | 1,924 | 4,725 | 4,801 | 6,306 | 1,843 |
| 1989 | 1,972 | 4,894 | 4,914 | 6,397 | 1,883 |
| 1990 | 2,023 | 5,095 | 5,032 | 6,487 | 1,923 |
| 1991 | 2,067 | 5,289 | 5,153 | 6,586 | 1,965 |
| 1992 | 2,111 | 5,454 | 5,256 | 6,685 | 2,008 |
| 1993 | 2,156 | 5,613 | 5,357 | 6,785 | 2,052 |
| 1994 | 2,201 | 5,763 | 5,465 | 6,884 | 2,097 |
| 1995 | 2,242 | 5,913 | 5,594 | 6,984 | 2,142 |
| 1996 | 2,277 | 6,059 | 5,728 | 7,118 | 2,189 |
| 1997 | 2,309 | 6,202 | 5,860 | 7,252 | 2,232 |
| 1998 | 2,339 | 6,342 | 6,000 | 7,387 | 2,276 |
| 1999 | 2,368 | 6,481 | 6,141 | 7,521 | 2,324 |
| 2000 | 2,396 | 6,650 | 6,268 | 7,655 | 2,366 |
| 2001 | 2,321 | 6,844 | 6,413 | 7,785 | 2,413 |
| 2002 | 2,452 | 7,035 | 6,551 | 7,917 | 2,461 |
| <u>Annual Rate of growth (percent)</u> | | | | | |
| 1988-1997 | 2.05 | 3.07 | 2.24 | 1.57 | 2.15 |
| 1988-2002 | 1.75 | 2.88 | 2.24 | 1.64 | 2.09 |

Source: Estomin and Kahal 1986a, 1986b; Kahal 1987b.

(a) This is the DP&L Group forecast. In addition to DP&L Company, it includes the coincident loads of Dover and Easton (approximately 6.9 percent of the total).

(b) Preliminary forecasts.

(c) Refers to winter ending in designated year.

**Table II-8
PPRP vs. company-prepared forecasts
(megawatts)**

| | APS | BG&E | DP&L | PEPCO |
|-------------|--------------|--------------|--------------|--------------|
| <u>1995</u> | | | | |
| PPRP | 6,984 | 5,913 | 2,242 | 5,594 |
| Company | <u>6,706</u> | <u>5,560</u> | <u>2,205</u> | <u>5,543</u> |
| Difference | + 278 | + 353 | + 37 | + 51 |
| <u>2002</u> | | | | |
| PPRP | 7,917 | 7,035 | 2,452 | 6,551 |
| Company | <u>7,565</u> | <u>6,280</u> | <u>2,500</u> | <u>6,035</u> |
| Difference | + 352 | + 755 | - 48 | + 246 |

Sources: Tables II-3 through II-7.

rates and financial risk.) Reliability means that the utility will have available the power supply resources to meet customer requirements at all hours of the year. On the other hand, utilities (with the strong concurrence of the PSC) prefer to avoid the high cost of acquiring and maintaining more resources than needed to meet their reliability standard.

The realities of power supply require the utility to maintain generating capacity sources in excess of annual peak demand. These realities include (a) unexpected forced outages of generating units during periods of high demand, and (b) the difficulties inherent in predicting peak demand. The desired reserve margins of a utility depend on a variety of factors including the load shapes that it serves, the strength of its interconnections with other utilities, the type and size of generating units and the utility's forced outage experience. Based on these factors, Maryland's utilities employ the following target reserve margins for planning purposes (BG&E 1988; DP&L 1987b; PEPCO 1987d; PE 1987):

APS - 25 percent
BG&E - 18 percent
DP&L - 15 percent
PEPCO - 16 percent

BG&E and DP&L adhere to PJM standards in setting their planning reserve targets. PEPCO was several studies and indicators, one of which is the PJM standard, for that purpose. How much reliability a utility system should provide is largely a matter of judgement, and the PJM pool uses the "one day in ten years" standard -- a degree of reliability consistent with the statistical likelihood that demand would not exceed capacity for any reason for more than one day in ten years (NERC 1987).

For the most part, the resource plans presented earlier in this chapter indicate that service will be adequate through 2002, if planned additions and purchases of power are made. For PEPCO and DP&L, reserve margins may be slightly below desired levels in the near term, but with subsequent resource additions, the margins rise to near the target levels. (An exception is DP&L, which at present does not list reserves after the mid-1990's.) These resource plans also indicate that

available reserves will not greatly exceed desired levels in any year. In contrast, many other areas of the country are presently experiencing severe excess capacity.

An assessment of future adequacy of service (and potential excess capacity problems) must go beyond the projected reserve margins, however, and consider the vulnerabilities of the plans. The most obvious area of uncertainty is the load forecast. Despite very rapid growth during the last few years, Maryland's utilities are projecting relatively slow rates of growth in peak demand -- less than 2.0 percent per year in each case. Whether this rate of growth takes place depends upon the local service area economies, electric rates, and the willingness of customers to undertake conservation voluntarily. Moreover, the utilities are including very ambitious estimates of load management savings. (BG&E's estimate is an exception, amounting to only three percent of its 2002 projected peak demand.) There has been little long-term experience in Maryland with such programs, and the savings estimates are to some extent a matter of conjecture.

There is some, although much less, uncertainty on the supply side. APS is relying very heavily over the next ten years on non-utility sources -- most of which are only in the negotiation stage. Enhancing the plan's reliability, however, is the fact that it includes a great many projects rather than one or two very large ones. A 20 percent contingency deduction has been included by APS to account for the possibility that some of the projects might not go forward. Non-utility power, at present, plays only a minor role in the resource plans of the other utilities.

At present, the other new sources of supply include Brandon Shores Unit 2 (BG&E), substantial additions of combustion turbine units (PEPCO, BG&E, and DP&L) and purchased power (PEPCO and BG&E). Some uncertainties exist, such as Ohio Power's contract with PEPCO, which allows Ohio Power to take back some of its committed capacity for its own customers in the latter years of the contract if necessary. However, there is no reason to identify any unusual reliability concerns with these sources. Combustion turbines have short lead times, and the other resources have been acquired or initiated.

In assessing the risks described above (particularly with load growth), it is necessary to examine the flexibility provided by the supply plans. Planning

flexibility is provided by (a) mothballed capacity; (b) altering the timing (and amount) of combustion turbines; and (c) exercising purchased power options. APS has placed its Springdale and Mitchell units, both oil-fired steam generating units, in cold storage reserve status. It has done so because it presently has sufficient capacity to serve its load, and because the Springdale and Mitchell units are relatively expensive to operate. The units can be reactivated when needed to serve load -- which is currently projected to occur in the late 1990's. However, if APS peak load grows faster than expected, their return to service can be accelerated as needed, thus providing planning flexibility. BG&E also has plans to mothball some of its capacity.

To assess reliability further, it is necessary to examine the regional electric power supply/demand balance, since this determines the opportunities Maryland utilities will have to supplement their current and planned capacity with purchases. For that purpose, the ten-year projections of the two regional electric power reliability councils -- the East Central Area Reliability Coordination Agreement (ECAR), which includes Potomac Edison, and the Mid-Atlantic Area Council (MAAC), which includes PEPCO, BG&E and DP&L -- have been consulted (NERC 1987). As of 1987, ECAR reports an overall reserve margin of 39 percent, while MAAC reports a 28 percent margin. (These projections, of course, are subject to their own uncertainties.) This indicates that, for the present and the near term, Maryland's utilities should be able to draw upon regional surpluses to maintain reliability if necessary. For 1996, the projected reserve margins fall to 27.7 percent and 25.0 percent respectively, for ECAR and MAAC. The availability of surplus capacity is expected to diminish over time and with it some planning flexibility for Maryland utilities.

D. Demand-Side Programs and Non-Utility Power Sources

Demand-Side Programs

Load management programs have seen increased emphasis in recent years, and they now play a major role in the planning processes of Maryland's major electric utilities. For the most part, these programs are designed to reduce demand at the time of the annual peak and to shift demand from the peak period (when demands

are high) to the lower demand, off-peak period. Some programs, such as high-efficiency appliance programs, may also lead to substantial reductions in total electric power consumption.

Table II-9 presents the year-by-year estimates of the annual peak demand reductions from demand-side programs, as provided to the Maryland PSC in each company's 1987 Ten-Year Plan submission. With the exception of PEPCO's "new EUM" savings, these reductions are incorporated into the company forecasts presented earlier in this chapter. These estimates apply to the "total system" rather than specifically to Maryland.

During the past several years, PEPCO has been putting in place a set of load management programs collectively referred to as its Energy Use Management (EUM) program. This program is projected to achieve savings of 500 MW by 1997, which is two-thirds the size of the two Station H plants. The major elements of the program, and the estimated load savings to be achieved by the mid- 1990's are as follows (PEPCO 1986):

- Expansion of mandatory time-of-use rates to medium-sized commercial customers and very large residential customers. This would include extending time-of-use rates to the Washington Metropolitan Area Transit Authority (WMATA). The estimated savings is projected to be 100 MW for the commercial customers and 15 MW for the residential customers.
- Curtailable service to commercial and governmental customers. Under this voluntary program, customers specify an amount of their load to be curtailed during those hours when the PEPCO peak load is pressing against available capacity. At times of high demand, PEPCO contacts the participating customer and requests the customer to reduce electric power usage. The projected load savings from this program are 205 MW.
- Residential direct load control. In exchange for a billing credit, customers permit PEPCO to install radio-controlled switches that

TABLE II-9

**Peak demand reductions from demand-side programs
(megawatts)**

| Year | APS | (a) | | PEPCO | |
|------|-----|------|------|-------------|-----------|
| | | BG&E | DP&L | Current EUM | "New" EUM |
| 1987 | 40 | - | - | 92 | 0 |
| 1988 | 85 | 68 | 15 | 117 | 0 |
| 1989 | 131 | 89 | 24 | 226 | 0 |
| 1990 | 182 | 113 | 50 | 273 | 0 |
| 1991 | 233 | 130 | 83 | 318 | 15 |
| 1992 | 288 | 146 | 117 | 357 | 38 |
| 1993 | 345 | 164 | 150 | 397 | 60 |
| 1994 | 404 | 180 | 181 | 433 | 82 |
| 1995 | 465 | 198 | 210 | 456 | 98 |
| 1996 | 525 | 213 | 225 | 470 | 113 |
| 1997 | 584 | 227 | 225 | 484 | 130 |
| 1998 | 645 | 164 | 225 | 494 | 146 |
| 1999 | 705 | 173 | 225 | 503 | 159 |
| 2000 | 766 | 183 | 225 | 515 | 171 |
| 2001 | 826 | 191 | 225 | 528 | 185 |
| 2002 | 888 | 199 | 225 | 540 | 199 |

Source: Ten-year plan filings with the Maryland Public Service Commission.

(a) Load management savings decline in 1997 due to shift to winter peak.